

Questions

1) What are the procedures now used in your region for economic dispatch? Who is performing the dispatch (a utility, an ISO or RTO, or other) and over how large an area (geographic scope, MW load, MW generation resources, number of retail customers within the dispatch area)?

Consumers Energy is located in a region that contains both the Midwest Independent Transmission System Operator (hereinafter Midwest ISO) and the PJM Interconnection, LLC (hereinafter PJM). Consumers Energy is a member of the Midwest ISO, while one of its natural trading partners, American Electric Power, is a member of PJM.

Both the Midwest ISO and PJM use a security constrained economic dispatch to dispatch generation. While all scheduled transactions are inputted into the State Estimator, not all transactions are subject to the security constrained economic dispatch. Market participants may submit either self-schedules or schedules reflecting bilateral transactions. These transactions are not subject to the economic dispatch. Both the Midwest ISO and PJM use security constrained economic dispatch which relies on bids placed into spot markets to dispatch generation that is neither self-scheduled nor scheduled pursuant to a bilateral transaction.

More specifically, the Midwest ISO operates two Energy Markets: Day-Ahead and Real-Time. The Day-Ahead Energy Market is a forward market in which hourly clearing prices are calculated for each hour of the next Operating Day based on the concept of Locational Marginal Prices (LMPs). The Day-Ahead Energy Market is cleared using Security-Constrained Unit Commitment (SCUC) and Security-Constrained Economic Dispatch (SCED) computer programs to satisfy Energy demand requirements of the Day-Ahead Energy Market. The results of the Day-Ahead Energy Market clearing include hourly LMP values and hourly demand and supply quantities. Conversely, the Real-Time Energy Market is a market in which the LMPs are calculated every five minutes, based on Midwest ISO Dispatch Instructions and actual system operating conditions, based on Midwest ISO's State Estimator. The Real-Time Energy Market dispatch is supported by a Reliability Assessment Commitment (RAC) process to ensure sufficient capacity is on line to meet Real-Time energy requirements.

The Midwest ISO performs the economic dispatch in the MISO footprint area. The area is comprised of 15 states and the province of Manitoba. According to the 2004 State of the Market Report – Midwest ISO by Potomac Economics, LTD, the Midwest ISO has 129,300 MWs of generation – 60% coal, 20% natural gas, and 17% nuclear, oil and Hydroelectric.

2) Is the Act's definition of economic dispatch (see above) appropriate? Over what geographic scale or area should economic dispatch be practiced? Besides cost and reliability, are there any other factors or considerations that should be considered in economic dispatch, and why?

Yes, the economic dispatch definition above is appropriate.

An economic dispatch should be limited to the physical capabilities of both the transmission and generation to the extent that each can provide an incremental cost savings to its customers.

A joint security constrained economic dispatch should be employed across the current footprints of the Midwest ISO and PJM pursuant to the Federal Energy Regulatory Commission's orders in Docket No. EL02-65, et al. On or before October 31, 2005, the RTOs are required to file a list of the elements of the Joint and Common Market along with the costs and benefits of each item. A stakeholder process is currently underway to determine what is included in the filing.

In 2002, the Midwest ISO, PJM and the Southwest Power Pool (SPP has subsequently withdrawn from the Joint and Common Market) jointly issued the attached study, which was prepared by ESAI, that quantifies the impact of a joint security constrained economic dispatch across the combined footprints of the three RTOs as resulting in a \$7 billion savings over a ten year period. In the current Joint and Common Market stakeholder process, Consumers Energy has requested that the RTOs update this study.

Cost and reliability are the only factors to consider in an economic dispatch. A significant consideration is that the models of generation and transmission used in economic dispatch must be sufficiently sophisticated to accurately model both the cost and physical responses of the equipment. Importantly, these models must be accurate over all operating time frames, and adaptable to changing equipment conditions. If these models are too simplified, the goal of cost minimization cannot be achieved.

3) How do economic dispatch procedures differ for different classes of generation, including utility-owned versus non-utility generation? Do actual operational practices differ from the formal procedures required under tariff or federal or state rules, or from the economic dispatch definition above? If there is a difference, please indicate what the difference is, how often this occurs, and its impacts upon non-utility generation and upon retail electricity users. If you have specific analyses or studies that document your position, please provide them.

Economic dispatch procedures can differ for various classes of generation, based on the physical and economic difference in generation types, and individual units. For example, coal generation may have limits in the way it is started or ramped up or down, compared with a peaking facility which could be started and stopped within a smaller period of time. Whether utility-owned or non-utility owned generation is dispatched is a matter of cost (as offered into the MISO market) and reliability. The utility-owned generation may

be lower cost compared to non-utility generation because utilities may tend to own more nuclear and coal-fired units with lower fuel costs. As such, the utility-owned (all else being equal, the lowest cost) generation will get dispatched first (if the system is unconstrained) followed by the non-utility generation. (We have not observed differences between tariff and operation.)

4) What changes in economic dispatch procedures would lead to more non-utility generator dispatch? If you think that changes are needed to current economic dispatch procedures in your area to better enable economic dispatch participation by non-utility generators, please explain the changes you recommend.

As noted in the previous response, the determinant of achieving greater dispatch is lower cost. An artificially higher price signal in an economic dispatch would lead to more non-utility generators being dispatched, but that would also result in the dispatch being less economic. As long as cost and reliability are the objective of the dispatch, no changes are needed. If a bias or subsidy masks the cost portion of a non-utility generator, obviously it could dispatch more, but at a higher overall cost.

5) If economic dispatch causes greater dispatch and use of non-utility generation, what effects might this have – on the grid, on the mix of energy and capacity available to retail customers, to energy prices and costs, to environmental emissions, or other impacts? How would this affect retail customers in particular states or nationwide? If you have specific analyses to support your position, please provide them to us.

If there were greater dispatch and use of non-utility generation, it may provide for a more reliable grid, (but not if more reliable or better located “utility” units are shut down) a greater capacity and mix of generation for retail customers, an increase in energy prices and costs, and perhaps lower environmental emissions.

But, on the whole, the greater the use of non-utility generation, the higher the costs would be to the retail customers.

6) Could there be any implications for grid reliability – positive or negative – from greater use of economic dispatch? If so, how should economic dispatch be modified or enhanced to protect reliability?

Economic dispatch, in theory, should lower costs without compromising reliability for all end-use customers. However, this assumes that reliability enforcement is an explicit goal of the dispatch. If cost is the main driver of the dispatch, reliability could suffer since cheaper power will be dispatched, and higher power flows will occur, thus increasing risk.